**PG&E's Comments on NEM Cost-Effectiveness Evaluation Study Proposal**

**November 5, 2012**

## I. Introduction

PG&E appreciates this opportunity to provide comments on the scope of the NEM cost-effectiveness evaluation, the data sources, the methodology, the avoided cost model and the sensitivity analyses to be included. PG&E generally supports the methodology to be employed and the proposed analyses. PG&E agrees with splitting the NEM Cost-Benefit Study into two phases, with the calculation of ratepayer impacts from NEM in Phase 1 and a separate white paper in Phase 2 that identifies and compares alternatives to NEM. P&GE further agrees with the proposed release date of a Draft Phase 1 report in January 2013 and a final Phase 1 report in first quarter 2013. PG&E further agrees that the Study need not speak to the overall societal value of renewable distributed generation, as the study is only required to fulfill the requirements of AB 2514 (Bradford, 2012) and Commission Decision ("D") 12-05-036, and specifically focus on the rate impact to non-participating customers.

In addition to the methodology, PG&E is generally in general agreement with the proposed data and avoided costs for the study, as presented by E3 at the workshop. However, PG&E has identified several critical items, which are discussed first, followed by general discussion of the project scope, data sources, methodology, avoided cost model, sensitivity analysis and reporting, with issues and discussion following the order of the workshop presentation by E3.

## II. Critical Issues

*A. "Counterfactual Condition"*: E3 correctly approaches the analysis by looking at the existing and potential future penetration of NEM systems, and determining the extent to which the output of these systems, including the power consumed directly on-site as well as the power that is exported at the full retail rate under NEM, causes rate impacts on non-participating customers. However, E3 believes that it must also determine how much rooftop generation – and associated cost-shift -- would have been created without the ability of customers to export power under NEM. E3 proposes to address this question through a "bookend" approach that includes an "export only" scenario associated with existing systems. PG&E questions whether developing such an analysis is necessary or helpful, or accurately describes what would have happened without the ability of customers to export power at the full retail rate as enabled under the current form of NEM. Neither the Decision, nor AB 2514 call for an analysis of how much generation would have been produced without the current form of NEM. Nor does the decision require completion of an "export-only" scenario, while AB 2514 specifically requires the analysis of the cost shift from all generation from NEM installations. PG&E believes that attempting to answer such a "counterfactual question" will unnecessarily divert critical time and resources from the central question of the study, which is how non-participating customers' rates are impacted from rooftop systems.

*B.* *Impacts of SB 695*: PG&E recognizes that in the prior evaluation of PV installations, E3 assumed that rate increases over the study period applied equally to all tiers of residential rates. This is incorrect, as PG&E stated at the workshop. SB 695 places limits on rate increases for the first two tiers for non-CARE customers, and allows only very limited increases for CARE customers, meaning that most residential rate increases are borne by rates for usage in non-CARE tiers 3 and above. Thus, any rate increases resulting from cost shifts from customers installing NEM, should only be applied to tiers 3 and above.

*C.* *T&D Benefits*: It is inappropriate to include any quantification of T&D upgrade deferrals in the base case of the cost shift calculations. In the first place, the proposed methodology does not conform to D.09-08-026 because it does not include the analysis required to estimate T&D benefits.[1] Second, even the existence of T&D deferral benefits has been controversial, with many parties arguing that NEM technologies do not possess the key characteristics to provide grid planners with the required certainty that the NEM systems would be available at the right times and with sufficient certainty to substitute for conventional investments. Finally, in some cases where there has been significant penetration of PV on local distribution circuits, there is anecdotal evidence that voltage problems ensue, requiring system upgrades to accommodate the NEM exports. In addition to post-installation system upgrades, many times the engineering analysis at the time of installation reveals the need for system upgrades. In both cases the NEM customer typically is not required to pay for the upgrades but instead these costs are born by other customers. PG&E suggests the necessary conclusion is that it would be inappropriate to assume deferral is probable. At a minimum, T&D benefits should be only included as a sensitivity.

E3 proposes to include "the value of deferring investments in transmission and distribution infrastructure" as a benefit of NEM. For PG&E, E3 proposes using the area-specific T&D marginal costs as filed in the 2014 test year GRC. While PG&E believes it is inappropriate to include T&D deferral benefits, the values given in the workshop presentation are accurate. P&GE includes only capital costs related to load growth in these estimates.

However, only a very small part of PG&E's capital spending for T&D is spent on system upgrades due to load growth (the only truly deferrable T&D). Most of the T&D capital budget is for elimination of bonus ratings on substations (a lesson learned from the 2006 heat storm) asset relocation, and replacement due to deterioration and storm damage.

[1] D.09-08-026 requires T&D investment deferrals for customer-side DG to be based on a study similar to that developed by Itron in the Sixth Year SGIP Impact Report. (D.09-08-026, p. 36. The Sixth Year impact report found no such benefits, and E3 indicated that it planned to conduct no such study.

*D.* *T&D Costs*: To the extent the IOUs can estimate the costs of system upgrades – both at the time of installation or as identified later – these costs should be included in the base case analysis whenever they are not paid by the customer with NEM generation.

*E.* *Integration Costs*: PG&E was disappointed to find that E3 planned to ignore integration costs caused by renewable generation. Integration costs have short- and long-run components and should be estimated just as E3 estimates avoided costs. Short-run components correspond to the provision of additional ancillary services in CAISO's short-term markets, such as regulation, additional commitment to clear the flexible ramping constraint, and (in the future) flexi-ramp services. There is also increased ramping requirements, which involve both additional commitment, loss of efficiency from increased starts and operating resources at suboptimal operating levels, and increased variable costs, mainly fuel but also additional operating costs form increased wear and tear of resources providing integration services.

Long-term components of integration costs are associated with the residual fixed cost of flexible capacity resources, which is not recovered in short-term energy and ancillary service markets. Given that new flexible capacity is likely needed before non-flexible capacity, the cost of flexible capacity will be higher than the cost of non-flexible capacity.

While PG&E understands that there is no exact quantification of these costs at this time, there is general agreement that they exist and will likely increase during the time covered in this analysis. PG&E suggests that the base case analysis include an integration cost of approximately $8.50.[2] If the CPUC wishes, a sensitivity analysis could be performed with a lower number, but it is inappropriate to ignore this critical issue entirely.

*F.* *Ancillary Services*: E3 proposes to include a benefit based on a theoretical reduction in ancillary service requirements due to reduction in load from customer-installed NEM generation. This is incorrect. For all of the reasons described above when discussing integration *costs* of renewable generation, it is inappropriate to assume there is any reduction in ancillary services. Today's ancillary services are primarily contingency reserves (spinning and non-spinning reserves), as well as regulation up and down. Contingency reserves are intended to cover major resource or transmission contingencies, which do not change because of NEM[3]. Regulation services actually *increase* as a result of additional wind and solar intermittent generation. Consequently, ancillary service benefits should be excluded from the analysis and integration *costs* should be substituted.

[2] PG&E's suggestion is based upon and consistent with the integration cost assumptions developed by E3 and adopted by the Commission for use as a standard planning assumption in the 2010 Long-Term Procurement Plan ("LTPP") proceeding.

[3] Contingency reserves are equal to the greater of 1) the largest single contingency, or 2) the sum of five percent of the load responsibility served by hydro generation and seven percent of load responsibility served by thermal generation, at least half of which must be spinning reserves.

PG&E's remaining comments on the scope, data, methodology, avoided cost calculations and sensitivity analyses are provided below, following the order of the workshop presentation.

## III. Scope of Work

*A. Export Only vs. all cost shifts*: Even though PG&E believes the analysis should not include estimates of the cost shift from exports only, PG&E understands that E3 and the Energy Division desire to address the export-only costs. Should the analysis include this calculation, PG&E strongly urges E3 to describe the results in a manner that will be understood by the legislature. Merely describing the issue as "counterfactual" without a careful description of what is and is not being presented may leave the impression that E3 is giving inaccurate information. In addition, E3 should indicate that in their professional judgment, the "true" counterfactual result is much closer to the all cost shift estimate, than to the export only book-end. Otherwise the reader may assume that the "cost of NEM" is some average of the two numbers.

*B. Utility Users Tax*: PG&E suggests that lost UUT revenues also be included in the analysis, to the extent the IOUs can provide estimates of the impact of NEM on UUT collections. While not a cost shift, lost UUT revenues can be critical to struggling cities.

## IV. Data Sources

*A. Incremental Billing Costs*: PG&E agrees that the differences between IOUs for incremental billing costs should be examined and is currently engaged in a re-examination of our own incremental billing costs. PG&E expects to provide updated incremental billing costs in a timely fashion for inclusion in this analysis.

*B. T&D Upgrade Costs*: As discussed earlier, increasing evidence indicates that NEM generation can have a negative impact on grid safety and reliability. We are aware that some installations require system upgrades at the time of installation and we are also aware that sometimes voltage problems can be created when more than one PV installation is interconnected on the same circuit. In most cases, ratepayers bear the cost burden for these upgrades, and they should be included in this analysis. Thus far, PG&E has not tracked these costs separately from other system upgrades, but we are assessing whether it is possible to quantify these costs for inclusion in this analysis.

*C. Cost Shift from NEM Installations on A6 and other Major Rate Schedules*: PG&E notes that the previous analysis did not include NEM installations where the customer was taking service under the A6 rate, and in fact, did not break out cost shifts by rate category. We believe that the exclusion of A6 underestimated the cost shift from non-residential installations because A6 has high on-peak rates and lack of a demand charge. PG&E expects E3 to include A6 customers and all other major rates in the instant analysis. However, PG&E also notes that E3 expects to compile both solar generation load shapes and customer load shapes at the hourly level. This could affect analysis of both A6 and A10 customers because the TOU periods for those rates change on the half-hour for some TOU periods. PG&E expects to work closely with E3 to ensure optimal estimation of bill savings.

## V. Methodology

*A. Line Losses*: PG&E agrees that NEM generation that serves at site load avoids line losses, but suggests that any exported electricity be treated like any other generation. Only site-specific analysis can determine whether exported generation increases or decreases line losses. Without such analysis, exports should be treated like any other power source and to assume line loss savings is inappropriate.

*B. Avoided CO2 Costs*: At some point, CO2 abatement costs will be embedded in the cost of energy and should no longer be added to the energy avoided cost. Further, CO2 avoided costs are already included in the RPS avoided cost and should not be double counted.

*C. Avoided RPS procurement*: PG&E generally agrees with E3's recognition that deployment of NEM generation will not affect RPS procurement in the short/medium term (E3 assumes after 2020). To the extent that NEM generation deployment were to avoid any RPS procurement once 2020 is reached, it would only do so to the extent that load is considered to be lower. Meaning that one kWh in NEM generation would lower load by a commensurate amount, resulting in the potential for 0.33 kWh in avoided RPS procurement. PG&E further notes that there may not be a value to a potential reduction in RPS procurement, if that procurement has already taken place. Furthermore, to the extent that RPS procurement can be avoided in 2020 or beyond, the value of a REC related to procurement at that time is likely be below $50/MWh. As California utilities achieve compliance with statutory renewable requirements, the above market cost of renewables is likely to fall.

PG&E has also seen arguments from the solar community that RPS value be increased to reflect the fact nonparticipants receive renewable power from their neighbors exports under NEM. This is flawed for two reasons. First, there is no avoided cost for nonparticipants, since almost all the exports are credited to the participating customers as sales reductions, so the IOU does not receive any generation procurement, regardless of the renewable nature of the generation source. The only renewable generation that the IOUs may potentially receive on behalf of non-participating customers is the annual excess generation compensated under the rules established in AB 920.[4] Second, it may be the case that, in fact, the customer-generator does not own the renewable attribute of that generation, so may not in fact receive the RPS value, much less provide it to their neighbors, because those RECs are often owed by the business that provides or finances the solar system. The only way the IOU can get RECs to help

[4] See D.11-06-016

with compliance is by buying them. As discussed above, as the IOUs meet the statutory renewable requirements, the value of RPS-qualifying energy diminishes. Furthermore, with the current "bucketing" limits in the RPS, the potential value that behind-the-meter RECs which the host or 3rd party owner could potentially provide have relatively low value.

## VI. Avoided Cost Model

A. PG&E supports E3's reason for using the 2011 update of its avoided cost model from the energy efficiency proceeding. Using an existing, previously vetted, public set of avoided costs will allow parties to focus their comments on the study itself, rather than on the avoided costs, and PG&E agrees this is a constructive trade-off against producing more current avoided costs, provided E3 incorporates the recommendations described below.

PG&E believes the carbon price forecast is reasonable.

*B. Resource Balance Year*:

PG&E appreciates E3's recognition that the calculation of avoided costs should not presume the resource that is being evaluated. However, PG&E notes that at the workshop E3 stated that the avoided cost curve used in their model was based on the energy efficiency avoided costs. It is not clear whether that includes Energy Efficiency which is forecast but not yet funded. PG&E recommends that the energy efficiency forecast should be restored to the load forecast used to determine the avoided cost curve and the rooftop solar forecast should be removed. This will ensure the appropriate calculation of, in particular, avoided capacity costs.

The resource balance year should not be assumed to always be the next year, with the result that the avoided capacity cost is always based on the cost of a new generation unit inclusion of capital avoided costs for the entire life of a NEM generator. Further, most foreseeable new generation additions will be required to be flexible in order to accommodate anticipated integration of renewables. Renewable generators do not have the attributes to avoid the need to acquire this type of resource, and in fact will increase the need for flexibility. Therefore, the RBY for the type of capacity that renewable DG can avoid is probably further out than the actual year that new flexible generation is needed, and the value for non-flexible capacity that renewable generation can help avoid is increasingly less valuable.

Caution must also be taken when considering the assumed reliability value of a MW of customer solar generation relative to a MW of conventional generation. First, rooftop solar tends to be fixed-tilt, south facing, which has lower availability in the late afternoon, hours which coincide with system peak. Secondly, over time, the peak hours of need will be shifting later in the day, thus reducing the relative capacity value of customer solar.

*C.* *Gas Costs*: E3 should consider updating gas costs, which remain well below the levels included in the current avoided cost model. Natural gas prices in E3's 2011 avoided cost calculator, based on December 2010 natural gas futures are about 20% higher than current natural gas prices.

## VII. Base Case – Sensitivities

*A.* *Base Case*: P&GE suggest the appropriate Base Case would incorporate the suggestions above, in particular **inclusion** of T&D upgrade costs (assuming IOUs can reasonable estimate them), **inclusion** of administration costs of NEM, including increased billing costs, **inclusion** of integration costs, **exclusion** of T&D upgrade deferral, and **exclusion** of ancillary services avoided costs.

*B.* *Avoided RPS Costs*: PG&E suggests adding a sensitivity that assumes the 2020 premium for renewable power is more in line with the REC value identified by the CPUC in the AB 920 decision, which was 1.8 cents per kWh.

*C.* *T&D Deferral*: T&D upgrade deferral benefits could be included as a sensitivity.

*D.* *Ancillary Services*: Avoided ancillary services should not be included.

*E.* *Integration Costs*: If the low end estimate of integration costs is included in the base case, then the higher estimate should be added as a sensitivity, and *vice versa*.

## VIII. Reporting Results

PG&E notes that AB 2514 requires an estimate of the PPP cost shift, which E3 did not specifically identify in the workshop presentation. PG&E recognizes that the PPP cost shift is likely contained within the revenue loss that E3 will calculate, so suggests that it be separately calculated and identified is not incremental to the other results.

E3 should provide the results of the sensitivity analyses for all three IOUs for all three penetration scenarios: 2011, full CSI and current NEM cap definition.

If the IOUs cannot provide reasonable estimates of the T&D system upgrade costs caused by NEM generation, this omission should be recognized in the Executive Summary and any results should clearly be identified as probably an underestimation.

## IX. Conclusion

PG&E thanks the CPUC and E3 for this opportunity to offer comments. PG&E is happy to work with the Energy Division and E3 to appropriately incorporate its suggestions. Feel free to contact Susan Buller at 415-973-3710 if you have any questions.

Sincerely,

Susan Buller